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The Protection of Synchronous Generators

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	Improvements in Signal Processing • Improvements in Protective Functions	

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In an apparatus protection perspective, generators constitute a special class of power network equipment because faults are very rare but can be highly destructive and therefore very costly when they occur. If for most utilities, generation integrity must be preserved by avoiding erroneous tripping, removing a generator in case of a serious fault is also a primary if not an absolute requirement. Furthermore, protection has to be provided for out-of-range operation normally not found in other types of equipment such as overvoltage, overexcitation, limited frequency or speed range, etc.

It should be borne in mind that, similar to all protective schemes, there is to a certain extent a “philosophical approach” to generator protection and all utilities and all protective engineers do not have the same approach. For instance, some functions like overexcitation, backup impedance elements, loss-of-synchronism, and even protection against inadvertent energization may not be applied by some organizations and engineers. It should be said, however, that with the digital multifunction generator protective packages presently available, a complete and extensive range of functions exists within the same “relay”: and economic reasons for not installing an additional protective element is a tendency which must disappear.

The nature of the prime mover will have some definite impact on the protective functions implemented into the system. For instance, little or no concern at all will emerge when dealing with the abnormal frequency operation of hydraulic generators. On the contrary, protection against underfrequency operation of steam turbines is a primary concern.

The sensitivity of the motoring protection (the capacity to measure very low levels of negative real power) becomes an issue when dealing with both hydro and steam turbines. Finally, the nature of the prime mover will have an impact on the generator tripping scheme. When delayed tripping has no detrimental effect on the generator, it is common practice to implement sequential tripping with steam turbines as described later.

The purpose of this article is to provide an overview of the basic principles and schemes involved in generator protection. For further information, the reader is invited to refer to additional resources dealing with generator protection. The ANSI/IEEE guides (ANSI/IEEE, C37.106, C37.102, C37.101) are particularly recommended. The *IEEE Tutorial on the Protection of Synchronous Generators* (IEEE, 1995) is a detailed presentation of North American practices for generator protection. All these references have been a source of inspiration in this writing.

2.1 Review of Functions

Table 2.1 provides a list of protective relays and their functions most commonly found in generator protection schemes. These relays are implemented as shown on the single-line diagram of Fig. 2.1.

As shown in the Relay Type column, most protective relays found in generator protection schemes are not specific to this type of equipment but are more generic types.

2.2 Differential Protection for Stator Faults (87G)

Protection against stator phase faults are normally covered by a high-speed differential relay covering the three phases separately. All types of phase faults (phase-phase) will be covered normally by this type of protection, but the phase-ground fault in a high-impedance grounded generator will not be covered. In this case, the phase current will be very low and therefore below the relay pickup.

TABLE 2.1 Most Commonly Found Relays for Generator Protection

Identification Number	Function Description	Relay Type
87G	Generator phase phase windings protection	Differential protection
87T	Step-up transformer differential protection	Differential protection
87U	Combined differential transformer and generator protection	Differential protection
40	Protection against the loss of field voltage or current supply	Offset mho relay
46	Protection against current imbalance. Measurement of phase negative sequence current	Time-overcurrent relay
32	Anti-motoring protection	Reverse-power relay
24	Overexcitation protection	Volt/Hertz relay
59	Phase overvoltage protection	Overvoltage relay
60	Detection of blown voltage transformer fuses	Voltage balance relay
81	Under- and overfrequency protection	Frequency relays
51V	Backup protection against system faults	Voltage controlled or voltage-restrained time overcurrent relay
21	Backup protection against system faults	Distance relay
78	Protection against loss of synchronization	Combination of offset mho and blinders

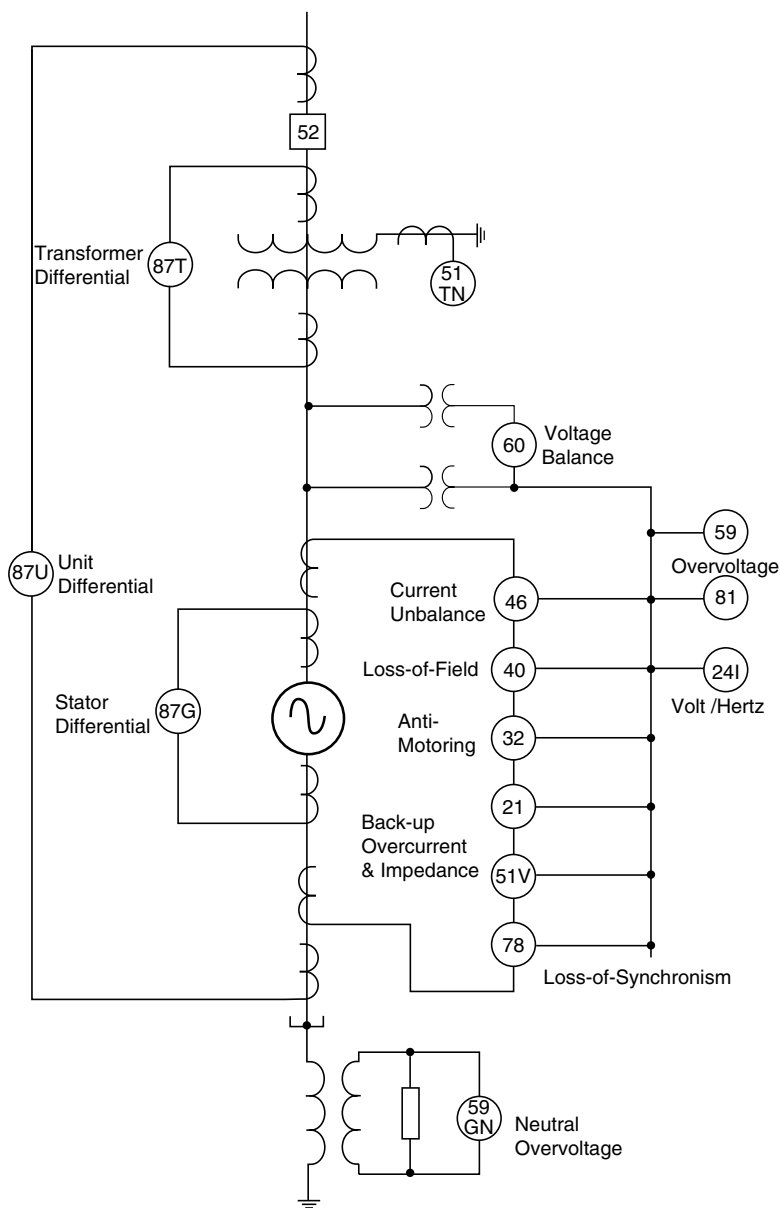


FIGURE 2.1 Typical generator-transformer protection scheme.

Contrary to transformer differential applications, no inrush exists on stator currents and no provision is implemented to take care of overexcitation. Therefore, stator differential relays do not include harmonic restraint (2nd and 5th harmonic). Current transformer saturation is still an issue, however, particularly in generating stations because of the high X/R ratio found near generators.

The most common type of stator differential is the percentage differential, the main characteristics of which are represented in Fig. 2.2.

For a stator winding, as shown in Fig. 2.3, the restraint quantity will very often be the absolute sum of the two incoming and outgoing currents as in:

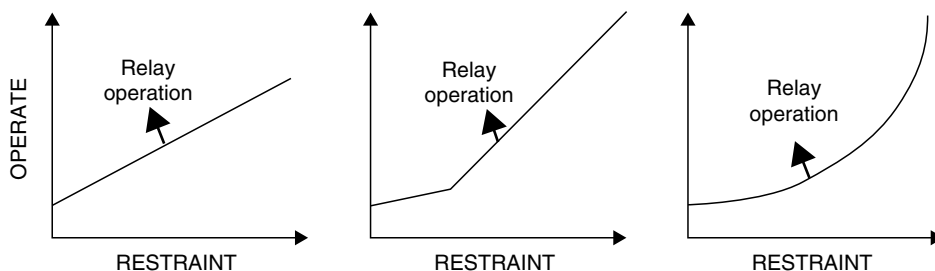


FIGURE 2.2 Single, dual, and variable-slope percentage differential characteristics.



$$I_{restraint} = \frac{|IA_{in}| + |IA_{out}|}{2}, \quad (2.1)$$

FIGURE 2.3 Stator winding current configuration.

whereas the operate quantity will be the absolute value of the difference:

$$I_{operate} = |IA_{in} - IA_{out}| \quad (2.2)$$

The relay will output a fault condition when the following inequality is verified:

$$I_{restraint} \geq K \bullet I_{operate} \quad (2.3)$$

where K is the differential percentage. The dual and variable slope characteristics will intrinsically allow CT saturation for an external fault without the relay picking up.

An alternative to the percentage differential relay is the high-impedance differential relay, which will also naturally surmount any CT saturation. For an internal fault, both currents will be forced into a high-impedance voltage relay. The differential relay will pickup when the tension across the voltage element gets above a high-set threshold. For an external fault with CT saturation, the saturated CT will constitute a low-impedance path in which the current from the other CT will flow, bypassing the high-impedance voltage element which will not pick up.

Backup protection for the stator windings will be provided most of the time by a transformer differential relay with harmonic restraint, the zone of which (as shown in Fig. 2.1) will cover both the generator and the step-up transformer.

An impedance element partially or totally covering the generator zone will also provide backup protection for the stator differential.

2.3 Protection Against Stator Winding Ground Fault

Protection against stator-to-ground fault will depend to a great extent upon the type of generator grounding. Generator grounding is necessary through some impedance in order to reduce the current level of a phase-to-ground fault. With solid generator grounding, this current will reach destructive levels. In order to avoid this, at least low impedance grounding through a resistance or a reactance is required. High-impedance through a distribution transformer with a resistor connected across the secondary winding will limit the current level of a phase-to-ground fault to a few primary amperes.

The most common and minimum protection against a stator-to-ground fault with a high-impedance grounding scheme is an overvoltage element connected across the grounding transformer secondary, as shown in Fig. 2.4.

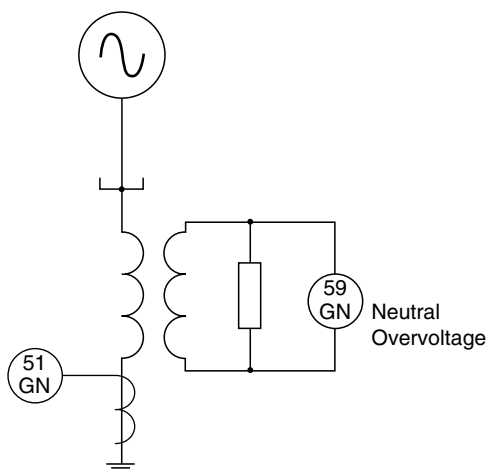


FIGURE 2.4 Stator-to-ground neutral overvoltage scheme.

For faults very close to the generator neutral, the overvoltage element will not pick up because the voltage level will be below the voltage element pick-up level. In order to cover 100% of the stator windings, two techniques are readily available:

1. use of the third harmonic generated at the neutral and generator terminals, and
2. voltage injection technique.

Looking at Fig. 2.5, a small amount of third harmonic voltage will be produced by most generators at their neutral and terminals. The level of these third harmonic voltages depends upon the generator operating point as shown in Fig. 2.5a. Normally they would be higher at full load. If a fault develops near the neutral, the third harmonic neutral voltage will approach zero and the terminal voltage will increase. However, if a fault develops near the terminals, the terminal third harmonic

voltage will reach zero and the neutral voltage will increase. Based on this, three possible schemes have been devised. The relays available to cover the three possible choices are:

1. Use of a third harmonic undervoltage at the neutral. It will pick up for a fault at the neutral.
2. Use of a third harmonic overvoltage at the terminals. It will pick up for a fault near the neutral.
3. The most sensitive schemes are based on third harmonic differential relays that monitor the ratio of third harmonic at the neutral and the terminals (Yin et al., 1990).

2.4 Field Ground Protection

A generator field circuit (field winding, exciter, and field breaker) is a DC circuit that does not need to be grounded. If a first earth fault occurs, no current will flow and the generator operation will not be affected. If a second ground fault at a different location occurs, a current will flow that is high enough to cause damage to the rotor and the exciter. Furthermore, if a large section of the field winding is short-circuited, a strong imbalance due to the abnormal air-gap fluxes could result on the forces acting on the rotor with a possibility of serious mechanical failure. In order to prevent this situation, a number of protecting devices exist. Three principles are depicted in Fig. 2.6.

The first technique (Fig. 2.6a) involves connecting a resistor in parallel with the field winding. The resistor centerpoint is connected the ground through a current sensitive relay. If a field circuit

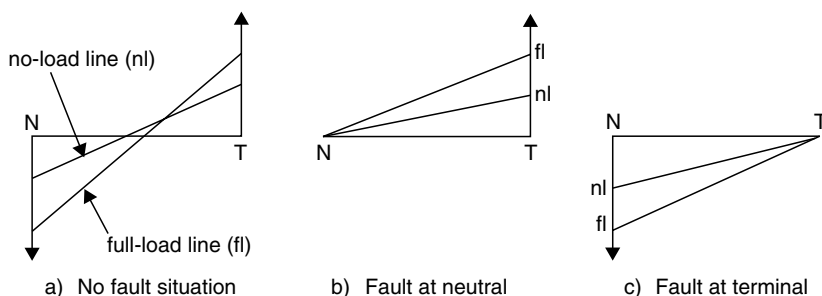


FIGURE 2.5 Third harmonic on neutral and terminals.

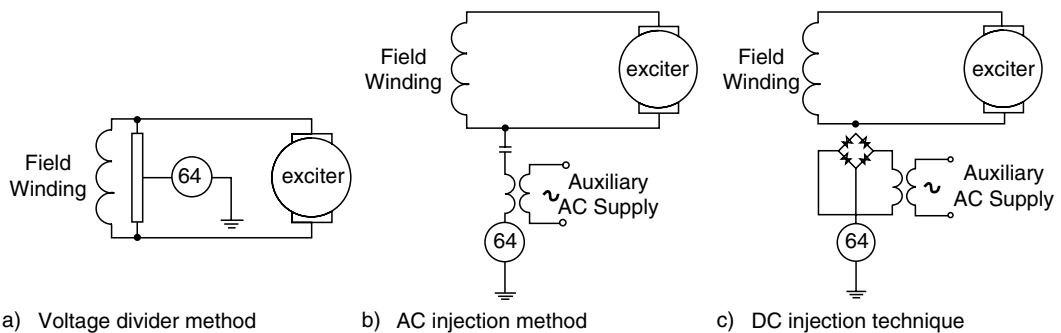


FIGURE 2.6 Various techniques for field-ground protection.

point gets grounded, the relay will pick up by virtue of the current flowing through it. The main shortcoming of this technique is that no fault will be detected if the field winding centerpoint gets grounded.

The second technique (Fig. 2.6b) involves applying an AC voltage across one point of the field winding. If the field winding gets grounded at some location, an AC current will flow into the relay and causes it to pick up.

The third technique (Fig. 2.6c) involves injecting a DC voltage rather than an AC voltage. The consequence remains the same if the field circuit gets grounded at some point.

The best protection against field-ground faults is to move the generator out of service as soon as the first ground fault is detected.

2.5 Loss-of-Excitation Protection (40)

A loss-of-excitation on a generator occurs when the field current is no longer supplied. This situation can be triggered by a variety of circumstances and the following situation will then develop:

1. When the field supply is removed, the generator real power will remain almost constant during the next seconds. Because of the drop in the excitation voltage, the generator output voltage drops gradually. To compensate for the drop in voltage, the current increases at about the same rate.
2. The generator then becomes underexcited and it will absorb increasingly negative reactive power.
3. Because the ratio of the generator voltage over the current becomes smaller and smaller with the phase current leading the phase voltage, the generator positive sequence impedance as measured at its terminals will enter the impedance plane in the second quadrant. Experience has shown that the positive sequence impedance will settle to a value between X_d and X_q .

The most popular protection against a loss-of-excitation situation uses an offset-mho relay as shown in Fig. 2.7 (IEEE, 1989). The relay is supplied with generator terminals voltages and currents and is normally associated with a definite time delay. Many modern digital relays will use the positive sequence voltage and current to evaluate the positive sequence impedance as seen at the generator terminal.

Figure 2.8 shows the digitally emulated positive sequence impedance trajectory of a 200 MVA generator connected to an infinite bus through an 8% impedance transformer when the field voltage was removed at 0 second time.

2.6 Current Imbalance (46)

Current imbalance in the stator with its subsequent production of negative sequence current will be the cause of double-frequency currents on the surface of the rotor. This, in turn, may cause excessive

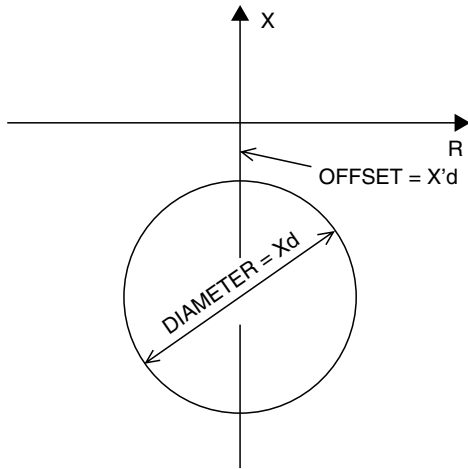


FIGURE 2.7 Loss-of-excitation offset-mho characteristic.

overheating of the rotor and trigger substantial thermal and mechanical damages (due to temperature effects).

The reasons for temporary or permanent current imbalance are numerous:

- system asymmetries
- unbalanced loads
- unbalanced system faults or open circuits
- single-pole tripping with subsequent reclosing

The energy supplied to the rotor follows a purely thermal law and is proportional to the square of the negative sequence current. Consequently, a thermal limit K is reached when the following integral equation is solved:

$$K = \int_0^t I_2^2 dt \quad (2.4)$$

In this equation, we have:

- K = constant depending upon the generator design and size
- I_2 = RMS value of negative sequence current
- t = time

The integral equation can be expressed as an inverse time-current characteristic where the maximum time is given as the negative sequence current variable:

$$t = \frac{K}{I_2^2} \quad (2.5)$$

In this expression the negative sequence current magnitude will be entered most of the time as a percentage of the nominal phase current and integration will take place when the measured negative sequence current becomes greater than a percentage threshold.

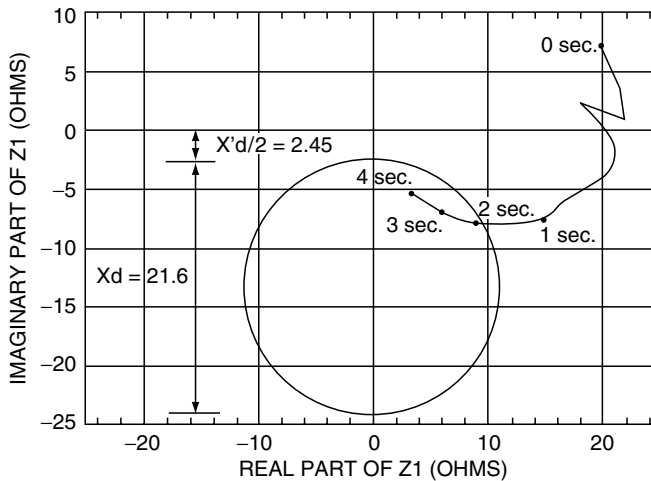


FIGURE 2.8 Loss-of-field positive sequence impedance trajectory.

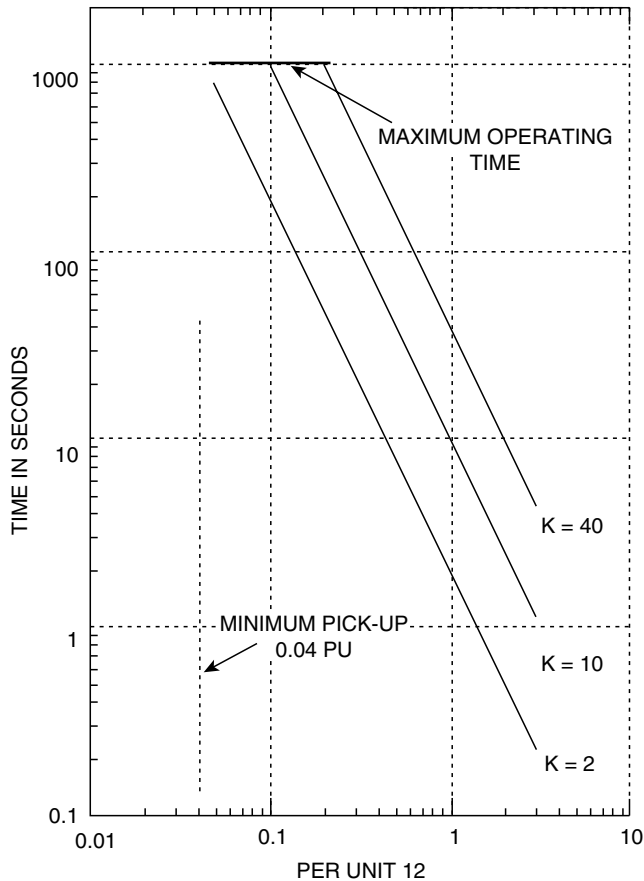


FIGURE 2.9 Typical static or digital time-inverse 46 curve.

Thermal capability constant, K , is determined by experiment by the generator manufacturer. Negative sequence currents are supplied to the machine on which strategically located thermocouples have been installed. The temperature rises are recorded and the thermal capability is inferred.

Forty-six (46) relays can be supplied in all three technologies (electromechanical, static, or digital). Ideally the negative sequence current should be measured in rms magnitude. Various measurement principles can be found. Digital relays could measure the fundamental component of the negative sequence current because this could be the basic principle for phasor measurement. Figure 2.9 represents a typical relay characteristic.

2.7 Anti-Motoring Protection (32)

A number of situations exist where a generator could be driven as a motor. Anti-motoring protection will more specifically apply in situations where the prime-mover supply is removed for a generator supplying a network at synchronous speed with the field normally excited. The power system will then drive the generator as a motor.

A motoring condition may develop if a generator is connected improperly to the power system. This will happen if the generator circuit breaker is closed inadvertently at some speed less than synchronous speed. Typical situations are when the generator is on turning gear, slowing down to a standstill, or has reached standstill. This motoring condition occurs during what is called “generator inadvertent

energization.” The protection schemes that respond to this situation are different and will be addressed later in this article.

Motoring will cause adverse effects, particularly in the case of steam turbines. The basic phenomenon is that the rotation of the turbine rotor and the blades in a steam environment will cause windage losses. Windage losses are a function of rotor diameter, blade length, and are directly proportional to the density of the enclosed steam. Therefore, in any situation where the steam density is high, harmful windage losses could occur. From the preceding discussion, one may conclude that the anti-motoring protection is more of a prime-mover protection than a generator protection.

The most obvious means of detecting motoring is to monitor the flow of real power into the generator. If that flow becomes negative below a preset level, then a motoring condition is detected. Sensitivity and setting of the power relay depends upon the energy drawn by the prime mover considered now as a motor.

With a gas turbine, the large compressor represents a substantial load that could reach as high as 50% of the unit nameplate rating. Sensitivity of the power relay is not an issue and is definitely not critical. With a diesel type engine (with no firing in the cylinders), load could reach as high as 25% of the unit rating and sensitivity, once again, is not critical. With hydroturbines, if the blades are below the tail-race level, the motoring energy is high. If above, the reverse power gets as low as 0.2 to 2% of the rated power and a sensitive reverse power relay is then needed. With steam turbines operating at full vacuum and zero steam input, motoring will draw 0.5 to 3% of unit rating. A sensitive power relay is then required.

2.8 Overexcitation Protection (24)

When generator or step-up transformer magnetic core iron becomes saturated beyond rating, stray fluxes will be induced into nonlaminated components. These components are not designed to carry flux and therefore thermal or dielectric damage can occur rapidly.

In dynamic magnetic circuits, voltages are generated by the Lenz Law:

$$V = K \frac{d\phi}{dt} \quad (2.6)$$

Measured voltage can be integrated in order to get an estimate of the flux. Assuming a sinusoidal voltage of magnitude V_p and frequency f , and integrating over a positive or negative half-cycle interval:

$$\phi = \frac{1}{K} \int_0^{T/2} V_p \sin(\omega t + \theta) dt = \frac{V_p}{2\pi f K} (-\cos \omega t) \Big|_0^{T/2} \quad (2.7)$$

one derives an estimate of the flux that is proportional to the value of peak voltage over the frequency. This type of protection is then called volts per hertz.

$$\phi \approx \frac{V_p}{f} \quad (2.8)$$

The estimated value of the flux can then be compared to a maximum value threshold. With static technology, volts per hertz relays would practically integrate the monitored voltage over a positive or negative (or both) half-cycle period of time and develop a value that would be proportional to the flux. With digital relays, since measurement of the frequency together with the magnitudes of phase voltages are continuously available, a direct ratio computation as shown in Eq. (2.8) would be performed.

ANSI/IEEE standard limits are 1.05 pu for generators and 1.05 for transformers (on transformer secondary base, at rated load, 0.8 power factor or greater; 1.1 pu at no-load). It has been traditional to

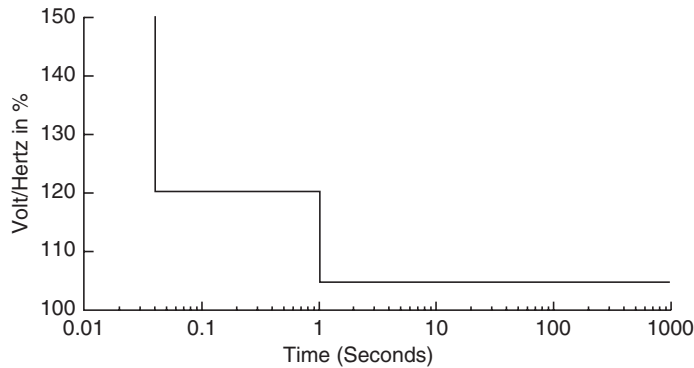


FIGURE 2.10 Dual definite-time characteristic.

supply either definite time or inverse-time characteristics as recommended by the ANSI/IEEE guides and standards. Fig. 2.10 represents a typical dual definite-time characteristic whereas Fig. 2.11 represents a combined definite and inverse-time characteristic.

One of the primary requirements of a volt/hertz relay is that it should measure both voltage magnitude and frequency over a broad range of frequency.

2.9 Overvoltage (59)

An overvoltage condition could be encountered without exceeding the volt/hertz limits. For that reason, an overvoltage relay is recommended. Particularly for hydro-units, C37-102 recommends both an instantaneous and an inverse element. The instantaneous should be set to 130 to 150% of rated voltage and the inverse element should have a pick-up voltage of 110% of the rated voltage. Coordination with the voltage regulator should be verified.

2.10 Voltage Imbalance Protection (60)

The loss of a voltage phase signal can be due to a number of causes. The primary cause for this nuisance is a blown-out fuse in the voltage transformer circuit. Other causes can be a wiring error, a voltage transformer failure, a contact opening, a misoperation during maintenance, etc.

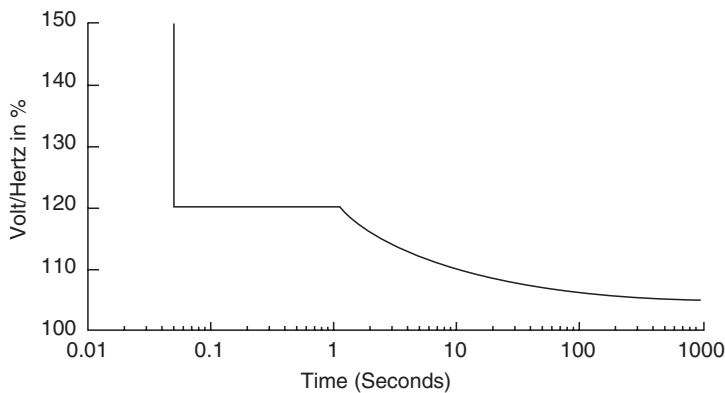


FIGURE 2.11 Combined definite and inverse-time characteristics.

Since the purpose of these VTs is to provide voltage signals to the protective relays and the voltage regulator, the immediate effect of a loss of VT signal will be the possible misoperation of some protective relays and the cause for generator overexcitation by the voltage regulator. Among the protective relays to be impacted by the loss of VT signal are:

- Function 21: Distance relay. Backup for system and generator zone phase faults.
- Function 32: Reverse power relay. Anti-motoring function, sequential tripping and inadvertent energization functions.
- Function 40: Loss-of-field protection.
- Function 51V: Voltage-restrained time overcurrent relay.

Normally these functions should be blocked if a condition of fuse failure is detected.

It is common practice for large generators to use two sets of voltage transformers for protection, voltage regulation, and measurement. Therefore, the most common practice for loss of VT signals detection is to use a voltage balance relay as shown in Fig. 2.12 on each pair of secondary phase voltage. When a fuse blows, the voltage relationship becomes imbalanced and the relay operates. Typically, the voltage imbalance will be set at around 15%.

The advent of digital relays has allowed the use of sophisticated algorithms based on symmetrical components to detect the loss of VT signal. When a situation of loss of one or more of the VT signals occurs, the following conditions develop:

- there will be a drop in the positive sequence voltage accompanied by an increase in the negative sequence voltage magnitude. The magnitude of this drop will depend upon the number of phases impacted by a fuse failure.
- in case of a loss of VT signal and contrary to a fault condition, there should not be any change in the current's magnitudes and phases. Therefore, the negative and zero sequence currents should remain below a small tolerance value. A fault condition can be distinguished from a loss of VT signal by monitoring the changes in the positive and negative current levels. In case of a loss of VT signals, these changes should remain below a small tolerance level.

All the above conditions can be incorporated into a complex logic scheme to determine if indeed a there has been a condition of loss of VT signal or a fault. Figure 2.13 represents the logic implementation of a voltage transformer single and double fuse failure based on symmetrical components.

If the following conditions are met in the same time (and condition) during a time delay longer than T1:

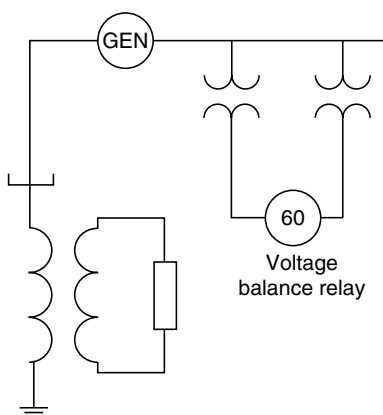


FIGURE 2.12 Example of voltage balance relay.

- the positive sequence voltage is below a voltage set-value SET_1,
- the negative sequence voltage is above a voltage set-value SET_2,
- there exists a small value of current such that the positive sequence current I1 is above a small set-value SET_4 and the negative and zero sequence currents I2 and I2 do not exceed a small set-value SET_3,

then a fuse failure condition will pick up to one and remain in that state thanks to the latch effect. Fuse failure of a specific phase can be detected by monitoring the level voltage of each phase and comparing it to a set-value SET_5. As soon as the positive sequence voltage returns to a value greater than the set-value SET_1 and the negative sequence voltage disappears, the fuse failure condition returns to a zero state.

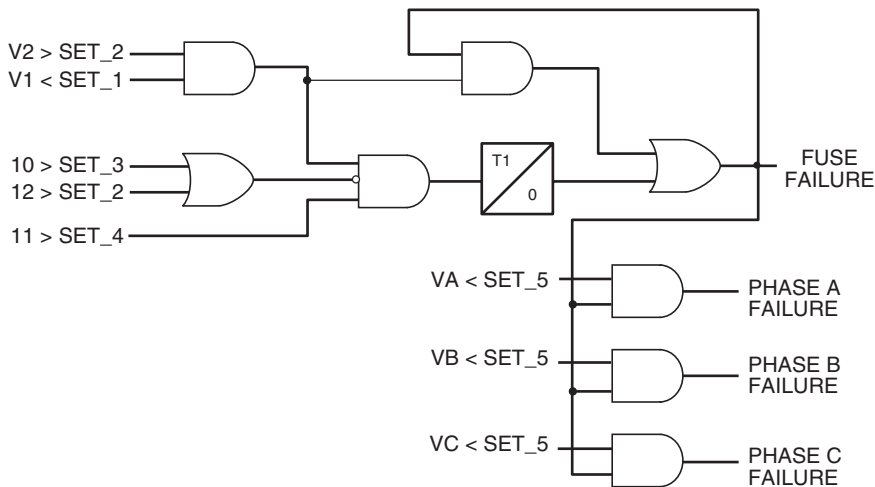


FIGURE 2.13 Symmetrical component implementation of fuse failure detection.

2.11 System Backup Protection (51V and 21)

Generator backup protection is not applied to generator faults but rather to system faults that have not been cleared in time by the system primary protection, but which require generator removal in order for the fault to be eliminated. By definition, these are time-delayed protective functions that must coordinate with the primary protective system.

System backup protection (Fig. 2.14) must provide protection for both phase faults and ground faults. For the purpose of protecting against phase faults, two solutions are most commonly applied: the use of overcurrent relays with either voltage restraint or voltage control, or impedance-type relays.

The basic principle behind the concept of supervising the overcurrent relay by voltage is that a fault external to the generator and on the system will have the effect of reducing the voltage at the generator terminal. This effect is being used in both types of overcurrent applications: the voltage controlled overcurrent relay will block the overcurrent element unless the voltage gets below a pre-set value, and the voltage restraint overcurrent element will have its pick-up current reduced by an amount proportional to the voltage reduction (see Fig. 2.15).

The impedance type backup protection could be applied to the low or high side of the step-up transformer. Normally, three 21 elements will cover all types of phase faults on the system as in a line relay.

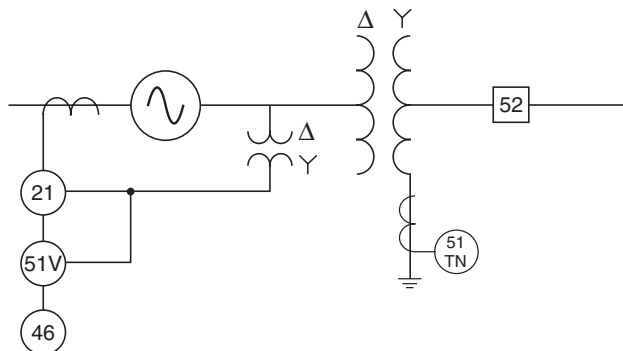


FIGURE 2.14 Backup protection basic scheme.

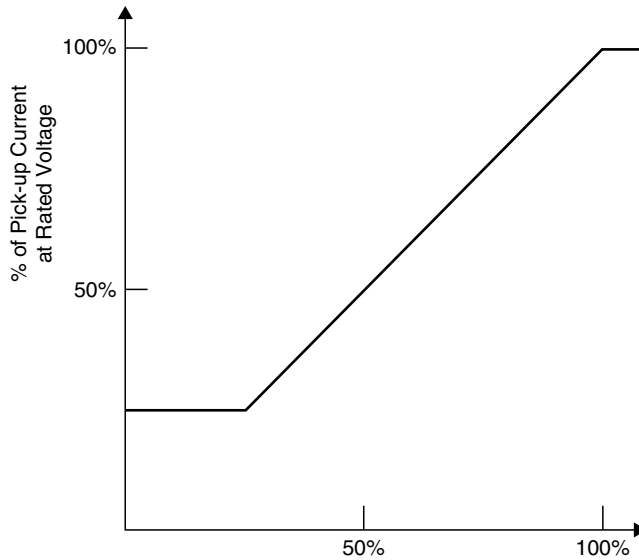


FIGURE 2.15 Voltage restraint overcurrent relay principle.

As shown in Fig. 2.16, a reverse offset is allowed in the mho element in order for the backup to partially or totally cover the generator windings.

2.12 Out-of-Step Protection

When there is an equilibrium between generation and load on an electrical network, the network frequency will be stable and the internal angle of the generators will remain constant with respect to each other. If an imbalance (loss of generation, sudden addition of load, network fault, etc.) occurs,

however, the internal angle of a generator will undergo some changes and two situations might develop: a new stable state will be reached after the disturbance has faded away, or the generator internal angle will not stabilize and the generator will run synchronously with respect to the rest of the network (moving internal angle and different frequency). In the latter case, an out-of-step protection is implemented to detect the situation.

That principle can be visualized by considering the two-source network of Fig. 2.17.

If the angle between the two sources is θ and the ratio between the voltage magnitudes is $n = E_G/E_S$, then the positive sequence impedance seen from location will be:

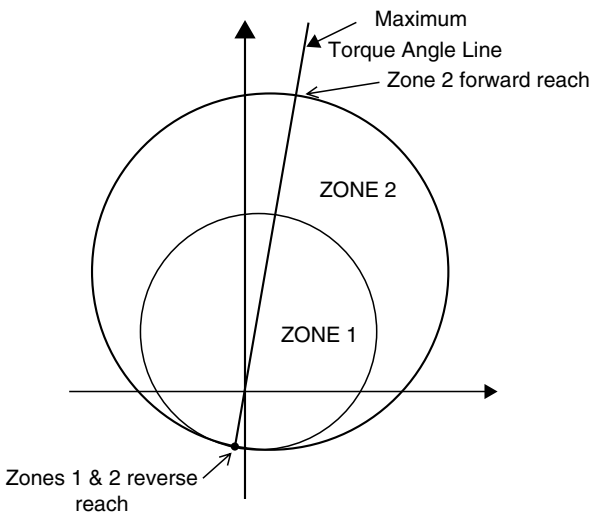


FIGURE 2.16 Typical 21 elements application.

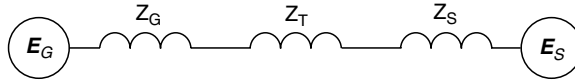


FIGURE 2.17 Elementary two-source network.

$$Z_R = \frac{n(Z_G + Z_T + Z_S)(n - \cos \theta - j \sin \theta)}{(n - \cos \theta)^2 + \sin^2 \theta} - Z_G \quad (2.9)$$

If n is equal to one, Eq. (2.9) simplifies to:

$$Z_R = \frac{n(Z_G + Z_T + Z_S)(1 - j \cot \frac{\theta}{2})}{2} - Z_G \quad (2.10)$$

The impedance locus represented by this equation is a straight line, perpendicular to and crossing the vector $Z_S + Z_T + Z_G$ at its middle point. If n is different from 1, the loci become circles as shown in Fig. 2.18. The angle θ between the two sources is the angle between the two segments joining Z_R to the base of Z_G and the summit of Z_S . Normally, that angle will take a small value. In an out-of-step condition, it will assume a bigger value and when it reaches 180° , it crosses $Z_S + Z_T + Z_G$ at its middle point.

Normally, because of the machine's inertia, the impedance Z_R moves slowly. The phenomenon can be taken advantage of and an out-of-step condition will very often be detected by the combination a mho relay and two blinders as shown in Fig. 2.19. In this application, an out-of-step condition will be assumed to be detected when the impedance locus enters the mho circle and remains between the two blinders for an interval of time longer than a preset definite time delay. Implicit in this scheme is the fact that the angle between the two sources is assumed to take a large value when Z_R crosses the blinders. Implementation of an out-of-step protection will normally require some careful studies and eventually will require some stability simulations in order to determine the nature and the locus of the stable and

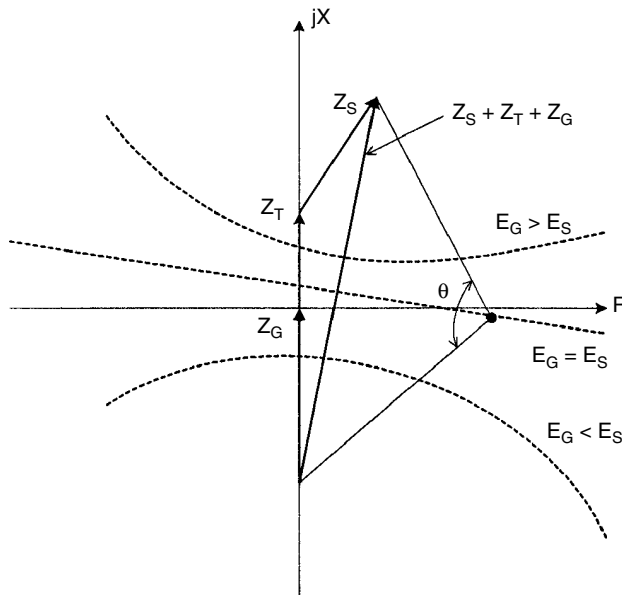


FIGURE 2.18 Impedance locus for different source angles.

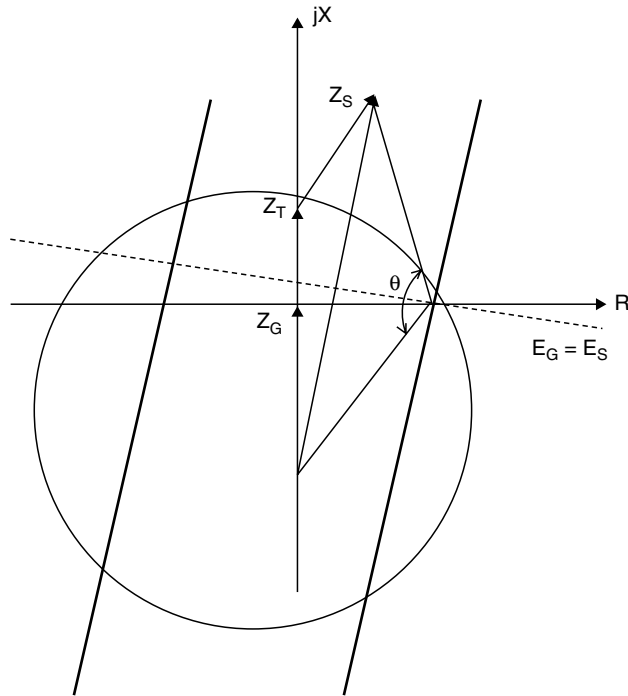


FIGURE 2.19 Out-of-step mho detector with blinders.

the unstable swings. One of the paramount requirement of an out-of-step protection is not to trip the generator in case of a stable swing.

2.13 Abnormal Frequency Operation of Turbine-Generator

Although it is not a concern for hydraulic generators, the protection against abnormal frequency operation becomes an issue with steam turbine-graters. If the turbine is rotated at a frequency other than synchronous, the blades in the low pressure turbine element could resonate at their natural frequency. Blading mechanical fatigue could result with subsequent damage and failure.

Figure 2.20 (ANSI C37.106) represents a typical steam turbine operating limitation curve. Continuous operation is allowed around 60 Hz. Time-limited zones exist above and below the continuous operation regions. Prohibited operation regions lie beyond.

With the advent of modern generator microprocessor-based relays (IEEE, 1989), there does not seem to be a consensus emerging among the relay and turbine manufacturers, regarding the digital implementation of underfrequency turbine protection. The following points should, however, be taken into account:

- Measurement of frequency is normally available on a continuous basis and over a broad frequency range. Precision better than 0.01 Hz in the frequency measurement has been achieved.
- In practically all products, a number of independent over- or under-frequency definite time functions can be combined to form a composite curve.

Therefore, with digital technology, a typical over/underfrequency scheme, as shown in Fig. 2.21, comprising one definite-time over-frequency and two definite-time under-frequency elements is readily implementable.

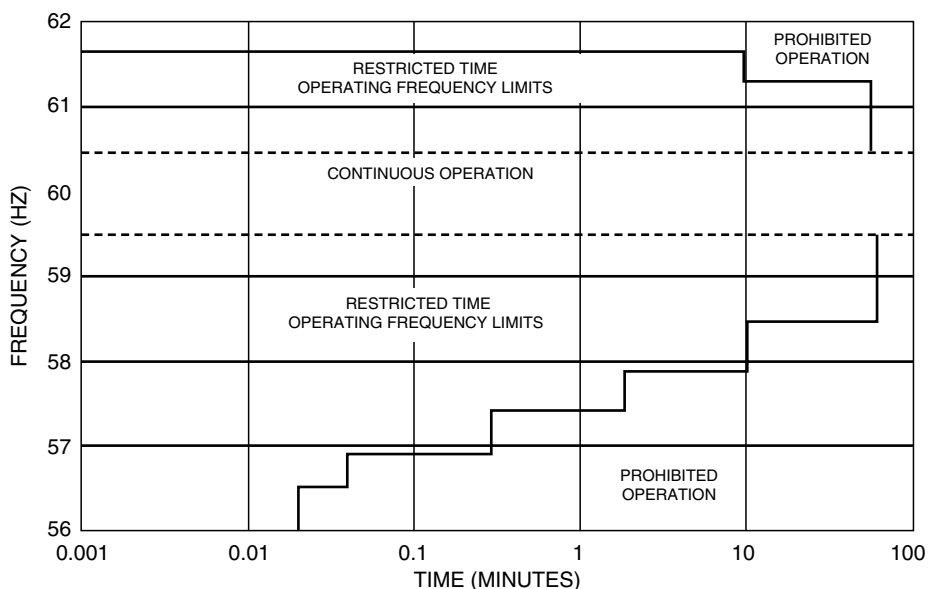


FIGURE 2.20 Typical steam turbine operating characteristic. (Modified from ANSI/IEEE C37.106-1987, Figure 6.)

2.14 Protection Against Accidental Energization

A number of catastrophic failures have occurred in the past when synchronous generators have been accidentally energized while at standstill. Among the causes for such incidents were human errors, breaker flashover, or control circuitry malfunction.

A number of protection schemes have been devised to protect the generator against inadvertent energization. The basic principle is to monitor the out-of-service condition and to detect an accidental energizing immediately following that state. As an example, Fig. 2.22 shows an application using an over-frequency relay supervising three single phase instantaneous overcurrent elements. When the

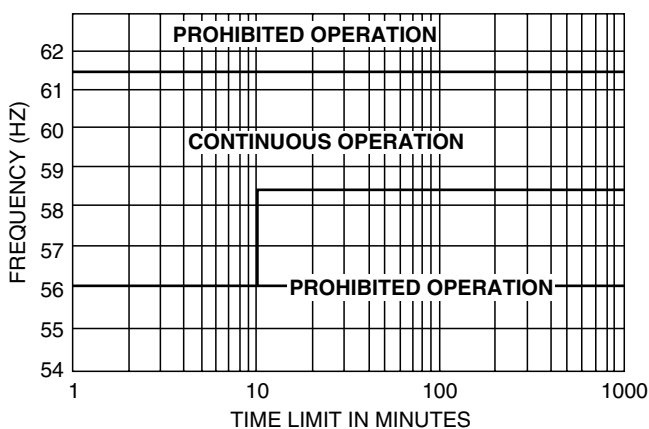


FIGURE 2.21 Typical abnormal frequency protection characteristic.

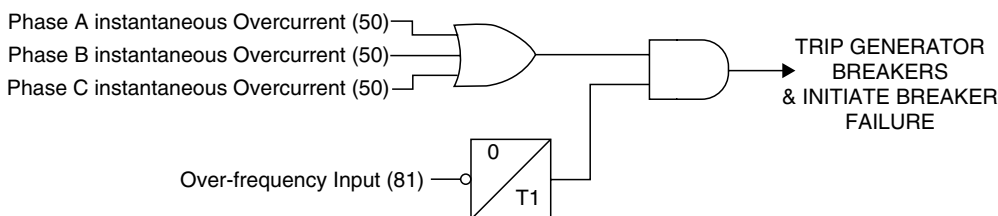


FIGURE 2.22 Frequency supervised overcurrent inadvertent energizing protection.

generator is put out of service or the over-frequency element drops out, the timer will pick up. If inadvertent energizing occurs, the over-frequency element will pick up, but because of the timer drop-out delay, the instantaneous overcurrent elements will have the time to initiate the generator breakers opening. The supervision could also be implemented using a voltage relay.

Accidental energizing caused by a single or three-phase breaker flashover occurring during the generator synchronizing process will not be detected by the logic of Fig. 2.22. In such an instance, by the time the generator has been closed to the synchronous speed, the overcurrent element outputs would have been blocked.

2.15 Generator Breaker Failure

Generator breaker failure follows the general pattern of the same function found in other applications: once a fault has been detected by a protective device, a timer will monitor the removal of the fault. If, after a time delay, the fault is still detected, conclusion is reached that the breaker(s) have not opened and a signal to open the backup breakers will be sent.

Figure 2.23 shows a conventional breaker failure diagram where provision has been added to detect a flashover occurring before the synchronizing of the generator: in addition to the protective relays detecting a fault, a flashover condition is detected by using an instantaneous overcurrent relay installed on the neutral of the step-up transformer. If this relay picks up and the breaker position contact (52b) is closed (breaker open), then a flashover condition is asserted and breaker failure is initiated.

2.16 Generator Tripping Principles

A number of methods for isolating a generator once a fault has been detected are commonly being implemented. They fall into four groups:

- Simultaneous tripping involves simultaneously shutting the prime mover down by closing its valves and opening the field and generator breakers. This technique is highly recommended for severe internal generator faults.
- Generator tripping involves simultaneously opening both the field and generator breakers.
- Unit separation involves opening the generator breaker only.
- Sequential tripping is applicable to steam turbines and involves first tripping the turbine valves in order to prevent any overspeeding of the unit. Then, the field and generator breakers are opened. Figure 2.24 represents a possible logical scheme for the implementation of a sequential tripping function. If the following three conditions are met, (1) the real power is below a negative pre-set threshold SET_1, (2) the steam valve or a differential pressure switch is closed (either condition indicating the removal of the prime-mover), (3) the sequential tripping function is enabled, then a trip signal will be sent to the generator and field breakers.

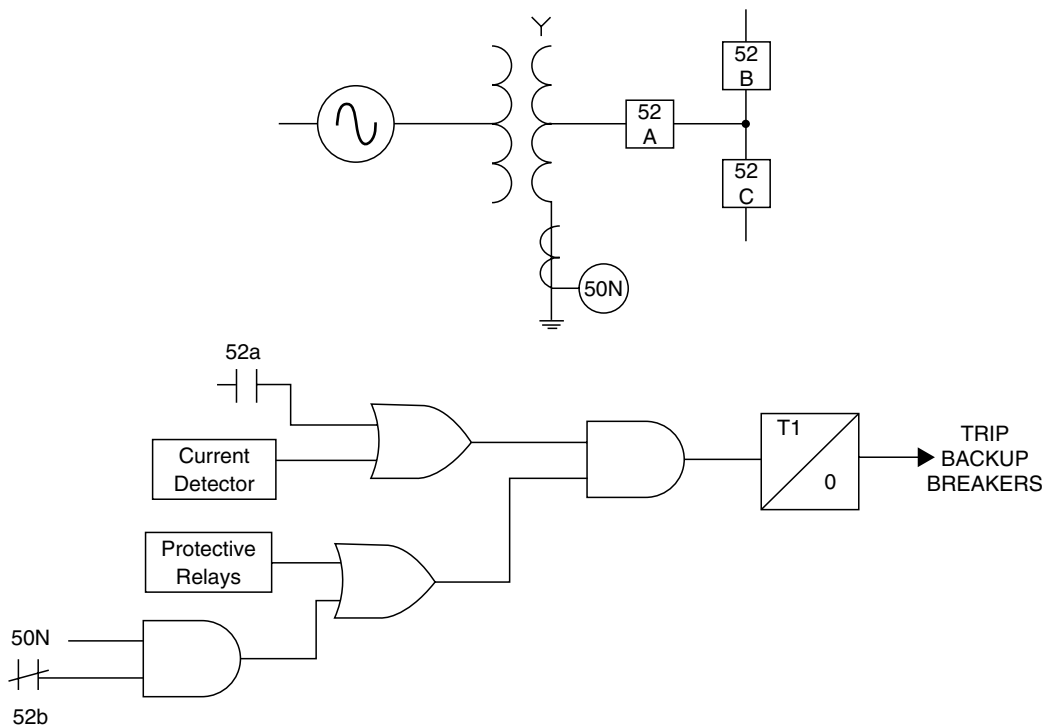


FIGURE 2.23 Breaker failure logic with flashover protection.

2.17 Impact of Generator Digital Multifunction Relays¹

The latest technological leap in generator protection has been the release of digital multifunction relays by various manufacturers (Benmouyal, 1988; Yalla, 1992; Benmouyal, 1994; Yip, 1994). With more sophisticated characteristics being available through software algorithms, generator protective function characteristics can be improved. Therefore, multifunction relays have many advantages, most of which stem from the technology on which they are based.

2.17.1 Improvements in Signal Processing

Most multifunction relays use a full-cycle Discrete Fourier Transform (DFT) algorithm for acquisition of the fundamental component of the current and voltage phasors. Consequently, they will benefit from the inherent filtering properties provided by the algorithms, such as:

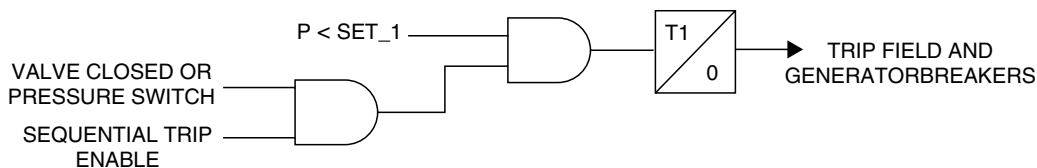


FIGURE 2.24 Implementation of a sequential tripping function.

¹This section was published previously in a modified form in Working Group J-11 of PSRC, Application of multifunction generator protection systems, *IEEE Trans. on PD*, 14(4), Oct. 1999.

- immunity from DC component and good suppression of exponentially decaying offset due to the large value of X/R time constants in generators;
- immunity to harmonics;
- nominal response time of one cycle for the protective functions requiring fast response.

Since sequence quantities are computed mathematically from the voltage and current phasors, they will also benefit from the above advantages.

However, it should be kept in mind that fundamental phasors of waveforms are not the only parameters used in digital multifunction relays. Other parameters like peak or rms values of waveforms can be equally acquired through simple algorithms, depending upon the characteristics of a particular algorithm.

A number of techniques have been used to make the measurement of phasor magnitudes independent of frequency, and therefore achieve stable sensitivities over large frequency excursions. One technique is known as frequency tracking and consists of having a number of samples in one cycle that is constant, regardless of the value of the frequency or the generator's speed. A software digital phase-locked loop allows implementation of such a scheme and will inherently provide a direct measurement of the frequency or the speed of the generator (Benmouyal, 1989). A second technique keeps the sampling period fixed, but varies the time length of the data window to follow the period of the generator frequency. This results in a variable number of samples in the cycles (Hart et al., 1997). A third technique consists of measuring the root-mean square value of a current or voltage waveform. The variation of this quantity with frequency is very limited, and therefore, this technique allows measurement of the magnitude of a waveform over a broad frequency range.

A further improvement consists of measuring the generator frequency digitally. Precision, in most cases, will be one hundredth of a hertz or better, and good immunity to harmonics and noise is achievable with modern algorithms.

2.17.2 Improvements in Protective Functions

The following functions will benefit from some inherent advantages of the digital processing capability:

- A number of improvements can be attributed to stator differential protection. The first is the detection of CT saturation in case of external faults that would cause the protection relay to trip. When CT ratios do not match perfectly, the difference can be either automatically or manually introduced into the algorithm in order to suppress the difference.
- It is no longer necessary to provide a Δ -Y conversion for the backup 21 elements in order to cover the phase fault on the high side of the voltage transformer. That conversion can be accomplished mathematically inside the relay.
- In the area of detection of voltage transformer blown fuses, the use of symmetrical components allows identification of the faulted phase. Therefore, complex logic schemes can be implemented where only the protection function impacted by the phase will be blocked. As an example, if a 51V is implemented on all three phases independently, it will be sufficient to block the function only on the phase on which a fuse has been detected as blown. Furthermore, contrary to the conventional voltage balance relay scheme, a single VT will suffice when using this modern algorithm.
- Because of the different functions recording their characteristics over a large frequency interval, it is no longer necessary to monitor the frequency in order to implement start-up or shut-down protection.
- The 100% stator-ground protection can be improved by using third-harmonic voltage measurements both at the phase and neutral.
- The characteristic of an offset mho impedance relay in the R-X plane can be made to be independent of frequency by using one of the following two techniques: the frequency-tracking

algorithm previously mentioned, or the use of the positive sequence voltage and current because their ratio is frequency-independent.

- Functions which are inherently three-phase phenomena can be implemented by using the positive sequence voltage and current quantities. The loss-of-field or loss-of-synchronism are examples.
- In the reverse power protection, improved accuracy and sensitivity can be obtained with digital technology.
- Digital technology allows the possibility of tailoring inverse volt/hertz curves to the user's needs. Full programmability of these same curves is readily achievable. From that perspective, volt/hertz protection is improved by a closer match between the implemented curve and the generator or step-up transformer damage curve.

Multifunction generator protection packages have other functions that make use of the inherent capabilities of microprocessor devices. These include: oscillography and event recording, time synchronization, multiple settings, metering, communications, self-monitoring, and diagnostics.

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